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BEFORE THE ARIZONA CORPORATION COMMISSION

JIM IRVIN
Commissioner - Chairman
RENZ D. JENNINGS
Commissioner
CARL J. KUNASEK
Commissioner

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.

DOCKET NO. RE-00000C-94-0165

TUCSON ELECTRIC POWER COMPANY'S EXCEPTIONS TO PROPOSED OPINION AND ORDER

On May 6, 1998, the Hearing Officer filed a Proposed Opinion and Order ("Proposed Order") in the above-captioned matter. Pursuant to the May 13, 1998 Procedural Order, Exceptions to the Proposed Order were to be filed on or before May 29, 1998. Tucson Electric Power Company ("TEP" or "Company") hereby files the following Exceptions to the Proposed Order.

INTRODUCTION

Even prior to the adoption of the Electric Competition Rules ("Rules") on December 26, 1996, one of the most controversial and contentious issues has been the Affected Utilities' ability to recover stranded costs. Rule A.A.C. R14-2-1607.B provides that, "The Commission *shall* allow recovery of unmitigated stranded costs by Affected Utilities." Despite what appears to be a clear mandate, many of the stakeholders in this process have taken the position that this Rule should either be interpreted or modified to provide the Affected Utilities an opportunity for recovery of something less than 100 percent of stranded costs. Hence, a generic proceeding that involved 20 days of hearings, 35 witnesses and over 4,000 pages of transcript was held to provide evidence to the Commission on this primary issue along with various ancillary issues.

TEP provided direct evidence and extensive legal analysis to demonstrate that it has a legal right to a reasonable opportunity to recover 100 percent of its stranded costs. TEP's legal analysis, based on the regulatory compact, as well as case law, was submitted to the Commission in its Initial and Reply Briefs filed on March 16 and 23, 1998, respectively. Rather than reiterate that analysis in these Exceptions, TEP hereby incorporates herein its Briefs by reference.

The Proposed Order sets out four objectives and attempts to balance the interests of the parties based upon those objectives. In summary, those objectives are to:

1. Provide the Affected Utilities a reasonable opportunity to collect 100 percent of unmitigated stranded costs;
2. Provide a mitigation incentive to provide a sharing of costs between ratepayers and shareholders;
3. Minimize the duration of the transition period consistent with other objectives; and
4. Minimize the stranded cost impact that remains on standard offer service.

Unfortunately, in order to accomplish the last three objectives, the Proposed Order does not fulfill the first objective; to provide the Affected Utilities a reasonable opportunity to collect 100 percent of unmitigated stranded costs. Moreover, the Proposed Order ignores evidence in the record of this proceeding and makes a series of assumptions not supported by the record. While the Proposed Order states that the Affected Utilities should have a reasonable opportunity for 100 percent recovery of stranded cost, TEP believes that the Proposed Order does not provide any opportunity for 100 percent recovery of stranded costs. Nor does it provide a balance between the potential for mitigation, term of recovery and the impact of reduced/eliminated returns on Affected Utilities. The Commission should also recognize the Affected Utilities' mitigation efforts to date and further look at each companies' specific opportunities for future mitigation. Further, regulatory assets cannot be mitigated. These are prior costs deferred by the *Commission* for future recovery. There is no ability to directly mitigate such costs. TEP also believes that up to ten years will be required to recover its stranded costs with no rate increases. Any required rate decreases increase the likelihood that ten years will be required to recover stranded costs. These factors must be balanced in order to provide Affected Utilities a real opportunity to recover 100 percent of stranded costs.

It also does not appear that the proposed options are structured so that they could be relied upon by utilities following the accounting guidelines of the Statement of Financial Accounting Standard No. 71, *Accounting for the Effects of Certain Types of Regulation* ("FAS 71") and related accounting literature that applies to rate-regulated enterprises. Failure to meet the FAS 71 criteria in any material way would result in write-offs that would financially cripple the Company.

For recovery of stranded costs to be recognized in the Affected Utilities' financial statements, the recovery paths must have the following characteristics:

- Cash flows must come from regulated revenues, rather than competitive revenues, even if it is probable that such competitive revenues will be earned by the entity. The cash flows can come from (1) rates charged directly as a tariffed rate; (2) as a competitive transition charge; or (3) through proceeds from securitized bonds which will be paid off through regulated revenues. In addition, the cash flows need to be certain enough to warrant reliance upon them as a recovery mechanism. This certainty level should be interpreted as 80 percent (or better) probability of occurrence.

- Recovery periods of five years or less would provide sufficient timeliness of recovery to ensure that the utility has a strong likelihood to recover its cost. If the plan provides for recovery over a five to ten year period, the plan *may* be considered adequately timely, but considerable doubt exists as to whether recovery over a period in excess of ten years would be sufficiently timely. The longer the recovery period, the greater the need for a true-up mechanism to allow the utility's cost recovery to be re-evaluated and modified. In the alternative, a greater amount of "head room" within the rate, or other increased evidence that the costs will be recovered by the end of the stated recovery period would be needed.

- A direct correlation between the costs incurred and the revenues being provided must exist. Setting rates, for example, based on a financial viability measure as proposed in Option No. 3 would to be an approach to ratemaking based on factors other than cost-of-service.

A write-off of stranded costs would likely have a negative impact on the ability of the Company to conduct its business. The write-off to equity could cause TEP to be in default under various credit agreements. In particular, TEP's bank credit agreement requires the Company to maintain a minimum level of common equity. As of March 31, 1998, the Company's equity balance was $215 million, which is only $49 million above the required minimum of $166 million. A default under the bank agreement could trigger cross defaults with other creditors and may increase the Company's cost of debt capital as lenders require a higher loan interest rate to compensate for the added TEP business risk and waiver of any default. Any default would also complicate TEP's ability to transition to a competitive utility market.

The Company's financial viability will also suffer as cash flows decline with less than 100 percent recovery of stranded costs. The Company needs to maintain cash flows to meet existing payment obligations such as fuel, lease payments, interest and O&M costs. These liabilities do not change as a result of asset values being adjusted. Reduced cash flows may cause the Company's credit ratings to decline, which could increase TEP's debt costs. These lower cash flows would reduce the Company's ability to comply with its bank credit agreement. In addition to the equity minimum described above, the credit agreement contains covenants relating to interest coverage and financial leverage, both of which are measured on cash flows available to the Company.

RECOVERY METHODOLOGIES

TEP will analyze each of the three recovery methodologies set forth in the Proposed Order in terms of their feasibility, as well as their financial and accounting implications to the Company. The Company will also propose alternatives that will permit these options to be potentially useful to TEP without incurring the financial harm that will result if these options are adopted without change.

It should be noted that the Proposed Order assumes that customers will have access at the phase-in rate of 20 percent in 1999, 50 percent in 2001 and 100 percent in 2003. However, subsequent statements regarding electric competition have suggested that one megawatt and above customers will have access in 1999 and all other customers in 2001 (with a retail pilot and an aggregation option in the interim.) It is not clear how the Proposed Order would apply in that case. TEP will attempt to point out areas where this is a concern.

Option No. 1 – Net Revenues Lost Methodology

Despite the Proposed Order's stated objective to provide the Affected Utilities a reasonable opportunity to recover 100 percent of their unmitigated stranded costs, the structure of this option as proposed will clearly not meet this objective.

Generation Assets

This option on the net revenues lost methodology states that customers who elect to participate in the competitive market will be obligated to pay a competitive transition charge ("CTC") equal to 100 percent of stranded costs directly assignable in year one, 80 percent in year two, 60 percent in year three, 40 percent in year four and 20 percent in year five, with no recovery thereafter. This 20 percent per year reduction does not provide an opportunity for the Affected Utilities to recover 100 percent of stranded costs. To justify this reduction, while taking the position that the option provides a reasonable opportunity for the Affected Utilities to collect 100 percent of their stranded costs, the Proposed Order states on page 12, line 4, that, "any shortfall the Affected Utility may have from the December 1998 customer base *could be more than made up from post 1998 customer growth.*" (Emphasis added.) This statement is <u>not</u> supported by anything in the record that indicates that Arizona as a whole, or each Affected Utilities' service territory, would have growth sufficient to support such reductions. Nor is there anything in the record which quantitatively proves the supposition that the 20 percent annual CTC reductions are adequately recovered from customer growth. Also, the Proposed Order states that "any such growth would be considered as mitigation which the Affected Utilities can retain." These statements must be quantified and any sharing of mitigation defined to determine their validity.

The only evidence of the growth rates appeared in the cross-examination of APS witness Jack Davis and of TEP witness Charles Bayless. When asked about the growth rate in Arizona, Mr. Davis replied that, with respect to APS' system, it "is in the neighborhood of long-term about two to two and a half percent." (Reporters Transcript of Proceedings ("Tr.") at 3867.) When asked a similar question regarding the Tucson area, Mr. Bayless responded, "We're down in the one and a half to two. It varies up and down. It may hit three some years." (Tr. at 1675.)

With 20 percent of customers in the first year and 50 percent of customers in the third year having access to the competitive market, the allocable portion of stranded cost at risk of non-recovery is quite high. The strong reliance on future growth and the hope that many customers will choose to stay on the Standard Offer rates does not provide TEP with a reasonable opportunity to recover stranded costs. The stranded cost amounts not recoverable through the more certain phased-in amounts would need to be estimated and written-off immediately due to FAS 71 requirements. Moreover, the decline in cash flows could reduce the Company's viability and its ability to comply with debt agreements as discussed above.

Regulatory Assets

The Proposed Order recognizes that "regulatory assets are more difficult for an Affected Utility to mitigate" but then reduces and ultimately eliminates the recovery of the return portion in order to encourage mitigation. The option provides that the regulatory assets would be recovered over their existing amortization periods, with a return on those assets phasing out over the first five years. In TEP's case, some of the regulatory assets have remaining amortization periods of 32 years. If the regulatory assets could not earn a return, the Company may have to immediately write-down the regulatory assets to their net present values. To avoid a write-down of the regulatory assets, the assets must earn a return at least equal to their interest carrying cost during the remaining amortization periods. It also appears unlikely that the costs could continue to be recovered over the remaining 32-year period, if the competitive markets are to be fully implemented within the next five years, without creating undue uncertainty and risk. This may cause an additional write-off of the amounts to be amortized in the period beyond the initial five years.

TEP proposes that under this option, regulatory assets be recovered through distribution rates over their previously planned lives and with full debt and equity returns. There is no potential for the Affected Utility to mitigate regulatory assets as they are previously incurred costs deferred for future recovery.

To summarize, it is not acceptable to write-off valid and prudently incurred costs due to failures to meet the requirements of FAS 71, which would then reduce the Company's financial viability. This option must provide a strong "opportunity" (of 80 percent probability or higher) for recovery of 100 percent of stranded costs (including generation assets, regulatory assets and at least an interest return thereon) over a period of not more than ten years through cash flows from regulated activities. Additionally, the CTC should be recoverable from all customers, including those customers under special contract.

Option No. 2 – Divestiture/Auction Methodology

The auction and divestiture method in the Proposed Order does not allow an opportunity for 100 percent recovery of stranded costs. It also lacks specificity. It does not offer an opportunity for 100 percent recovery as it provides no carrying charges over a ten-year recovery period and annual collections may potentially be reduced if an artificial rate cap is exceeded. The lack of carrying costs reduces recovery levels to 68 to 75 percent (assuming carrying costs of 7 to 10 percent). Accordingly, this would decrease the Company's financial viability and the likelihood of sustaining FAS 71 accounting. The level of recovery may be reduced further if stranded costs are deferred due to rate cap issues. This may be a significant problem over a ten-year recovery horizon as electric prices are expected to rise over that time frame. Further, TEP believes that a more precise definition of stranded cost is needed. Although any implementation plan will necessarily entail further definition through actual cost filings, for purposes of amendment to the Proposed Order, TEP believes stranded costs should be defined as "the basis of the generation assets, less proceeds net of all costs, including taxes." Basis equals total cost less disallowance.

The divestiture option must provide greater specificity regarding the type of costs that will be recoverable given the unique financial and ownership structure of the Company's generating assets.

For example, the Company may not be able to divest its leasehold interests without incurring premiums, penalties or other payments to the lessors and debt participants. Any such payments must be explicitly included as elements of stranded costs. In addition, a significant portion of the Company's generating assets are financed with tax-exempt two-county debt. Such debt may have to be redeemed upon transfer of the assets. Also, the remaining distribution assets may no longer qualify for two-county financing, thus requiring the Company to refinance the tax-exempt debt with taxable financing. Under such circumstances, the Company must be able to recover the higher average interest cost. Similarly, costs associated with the transfer of the Company's fuel and transportation contracts and its interests in jointly-owned generating facilities must be accounted for in determining the costs associated with divestiture. Furthermore, all tax ramifications of a divestiture should be recoverable by the Affected Utility.

In order to complete the divestiture of its generating assets, the Company may be required to (1) redeem debt obligations associated with the assets, (2) compensate substitute lessees for assuming the Company's obligations under its leveraged leases, and/or (3) pay premiums or penalties to lessors, debt participants, fuel and transportation providers or participants in jointly-owned facilities, all as discussed previously. The cash required to make such payments may exceed the proceeds received by the Company from the divestiture of the assets. Consequently, funding would be required to finance the potential cash requirement.

The additional funds which may be required to effect divestiture could be obtained by the local distribution company (*i.e.*, TEP, upon divestiture) through one or more financings. The financing would be dependent on the CTC the Company collects for its stranded costs. Lenders would look to the CTC cash payments as the source for the payment of interest and principal on the new loan(s). The loan terms (including the amount, interest rate and maturity) would be determined by the size and duration of the CTC and, of key importance, assurance that the CTC is an irrevocable obligation, subject to change only for true-up. One means of obtaining such assurance is through an order of the Commission, which addresses the irrevocability of the CTC. To provide additional assurance and enhanced financing ability, the approved Commission order should clearly create a property right in the transition property for the benefit of a special bankrupt-proof entity. Bonds

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secured with such property rights could probably be issued by the special purpose entity on more favorable terms than the local distribution company would receive, thereby reducing costs to customers.

TEP also believes that because it could take up to two years to complete the auction and divestiture, the option should provide for an interim CTC to commence with the introduction of competition on January 1, 1999 to be paid by all non-standard offer customers. After divestiture and upon the setting of the permanent CTC, the amounts collected on an interim basis would be factored in.

The divestiture option states that it will provide 100 percent of stranded cost recovery over a period of ten years. However, later the Proposed Order contradicts that intent by stating that the recovery is subject to a rate cap, uncollected amounts are to be deferred to future periods and no return is to be earned on the deferred balance. As with Option No. 1, the failure to have a return may result in an immediate write-down of assets to their net present value. In addition, there is no discussion about what happens to stranded cost amounts deferred beyond the ten-year period, which would not be collected due to the rate cap. The existence of the rate cap could preclude the recovery of a significant amount of stranded costs. The amount not expected to be recovered due to the rate cap would be estimated and written off immediately.

The divestiture option *must state that due to unforeseen circumstances*, such as a higher than expected amount of stranded cost after divestiture or reduced levels of recovery resulting from the rate cap, the recovery period for the CTC may be extended by the Commission in order to provide for the opportunity for 100 percent recovery and to support any securitization. Finally, the option should provide that regulatory assets, together with a return thereon, are recoverable as part of the CTC or distribution charge, as appropriate.

The divestiture option also does not address the possibility that no acceptable bids will be received for the generating assets, or that the Commission does not approve a submitted divestiture plan or any portion thereof. Under such circumstances, the Affected Utility should have a reasonable opportunity for recovery of 100 percent of unmitigated stranded costs under a net revenues lost approach similar to Option No. 1 with TEP's proposed modifications.

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Option No. 3 – Financial Integrity Methodology

This option is vague and needs considerable specificity. The Commission has a legal obligation to prescribe just and reasonable rates and allow for a reasonable return on the fair value of a utility's property. This is a higher standard than minimum financial integrity. The option as proposed could be interpreted to mean that the Commission will provide sufficient revenues to provide one dollar over bankruptcy or sufficient revenues to meet financial obligations but will provide no return to shareholders. It could also require that Affected Utilities are provided adequate revenues to maintain investment grade ratings.

This option states that the rates would be set to maintain the financial viability of the entity for a period of ten years and, thereafter, there would be no more stranded cost recovery. The option does not state how, or whether, stranded costs would actually be recovered. The method of recovery must be tied to the entity's costs incurred for it to be recognizable under FAS 71, and sufficient cash flows must be provided to maintain financial viability and avoid defaults. If recovery is provided through all the necessary cash flows, but such cash flows are derived from a method of ratemaking other than one that is cost-based, it will not be recognizable in the Affected Utilities' financial statements. TEP believes that this option should provide for sufficient revenues for an Affected Utility to reach and maintain an investment grade credit rating, but through a cost-based revenue calculation collecting 100 percent of stranded cost so that FAS 71 write-offs do not result.

INDIVIDUAL STRANDED COST FILINGS

TEP believes that 30 days to file its choice of option and implementation plan is unreasonable, especially given the lack of clarity regarding the three options. TEP cannot make a reasoned decision in such a short period of time and with such limited detail.

PROPOSED CHANGE TO RULE R14-2-1607.B

The Proposed Order also calls for the addition of language to Rule R14-2-1607.B so that it would read, "The Commission shall allow *a reasonable opportunity for* recovery of unmitigated Stranded Cost by the Affected Utilities." Although TEP supports this modification in concept (and has used this language), it could be detrimental to the Affected Utilities, depending on the intent of the term *reasonable opportunity*. As noted earlier, for the Affected Utilities to retain the affected assets on their financial statements, the assets must be "probable" of recovery. As previously discussed, in an accounting sense, that means recovery is "likely" to occur, which is generally interpreted as having a probability of 80 percent or higher. If the intent, as it appears under all three options, is that the utilities will not recover 100 percent of stranded costs, then write-offs are likely to occur. The intent of the language in the Rules and in the proposed options must provide for a real opportunity. While this does not represent a guarantee, it does represent a reasonably high degree of probability of recovery. Rule R14-2-1607.B, as currently written, contains that high degree of probability and should not be amended. However, if the Commission makes this modification, the Proposed Order should clarify its intent so as not to jeopardize the accounting treatment of such generation and regulatory assets.

SHOULD THERE BE A PRICE CAP OR RATE FREEZE?

TEP believes that a price cap is contradictory to a competitive environment and may conflict with an Affected Utilities' ability to recover stranded costs. However, as discussed above, to the extent the Commission determines the need for a rate cap to be implemented, the Affected Utilities should not be unfairly penalized in terms of their ability to recover stranded costs via the CTC for circumstances outside of their control. If the CTC is required to be lowered due to the cap, the recovery period should be extended to provide the Affected Utility the opportunity to collect all of its stranded costs.

OTHER ISSUES

Special Contracts

TEP believes that special contract customers should be responsible for stranded costs just as all other customers. As proposed, all customers would pay stranded costs based on their current allocations of costs for ratemaking purposes. To the extent that such allocated costs are in contracted rates, current contract price levels should not be exceeded when prices, including stranded costs, are unbundled for competition. Customers whose contracts have lower pricing levels than their previous allocations for ratemaking purposes, must either be responsible for costs up to their allocated level or such cost differences should be reallocated. Otherwise, Affected Utilities will be required to write-off any shortfalls. Further, special contract customers must be responsible for stranded cost recovery through the full period of recovery. Otherwise, the allocations to other customer classes, or Affected Utility write-offs, will be excessively large. There also may be a "fairness" problem if such customers are "off the hook" far in advance of other customers solely due to the fact that they had contracts.

Exit Fees

Although TEP supports the opinion regarding exit fees, again, more definition is needed. For example, how do you calculate the impact of exit fees in conjunction with periodic true-ups?

Self-Generation Exclusion

TEP also disagrees with the assertion in the Proposed Order that Rule R14-2-1607.J should not be modified. If the Rule is not modified to ensure that customers who choose to self-generate are responsible for stranded costs just as any other existing customer, a potentially large and improper economic incentive for self-generation will be created. This is due to the ability of such customers to avoid stranded cost charges. The result of the Rule as written will be to significantly increase self-generation while increasing stranded cost burdens on customers who purchase their power in the competitive marketplace. This is of particular importance to ensure that special contract customers pay their fair share as discussed above.

Market Price

Footnote 7 on page 13 of the Proposed Order references the Palo Verde Dow Jones Index or the California Power Exchange Index. TEP is in agreement with these proxies for market generation. Footnote 7 further states that, "any market price should include a blend of spot, short term, and long term power." The Proposed Order needs further clarification of the "blend" needed to determine the market price for generation. TEP believes that any blend should be directly correlated to the true-up or recalculation period in order to ensure that Affected Utilities have the ability to closely match their market opportunities to the computation index in order to minimize the potential to recover shortfalls. Otherwise, TEP does not support a blended market price.

Infrastructure Costs

Page 14, lines 4-6 of the Proposed Order states, "While the Affected Utilities may have additional costs related to transactions in implementing electric competition, those costs, if reasonable, can be factored into the market price." TEP takes exception to this statement. The cost of infrastructure required to implement competition should be borne by the customer via a distribution transition charge levied on all customers. Affected Utilities should not be put at a competitive disadvantage by bearing the costs of the required infrastructure to implement competition. As is evident by other states' experiences, such costs are not trivial and must be shared equitably by <u>all</u> participants in the new marketplace.

Prudency

Page 15, line 28 of the Proposed Order states, "It is not the Commission's intent to go back and revise previous prudency determinations." Yet the next sentence contradicts the previous sentence by stating that, "This does not mean that the Commission may not consider changed circumstances and resulting management decisions subsequent to previous prudency determinations." TEP supports the proposed AEPCO prudency exclusion. Rule R14-2-1607.I should be amended to provide specific language that prior prudency decisions will not be revisited.

CONCLUSION

Although TEP is supportive of bringing retail competition to Arizona as soon as practicable, the issues relating to stranded costs must be resolved prior to the advent of competition. The generic hearing which resulted in the Proposed Order was a necessary step toward providing guidance on those issues. While the Proposed Order attempts to balance the interests of all stakeholders, it omits critical details necessary to provide the Affected Utilities with a reasonable opportunity to recover 100 percent of their stranded costs, which may have significant financial and accounting implications to the Company. In the foregoing Exceptions, TEP has attempted to provide constructive and crucial comments that must be incorporated into the Proposed Order if it is to be adopted. At stake is the ultimate disposition of hundreds of millions of dollars of assets resulting from the determination to change from a regulated to a competitive environment. It is essential that the Commission take the necessary action to amend the Proposed Order to address the issues raised in these Exceptions. If this is accomplished, the Commission will have taken a giant step toward resolving the stranded cost issue and bringing retail electric competition to Arizona. The alternative may be costly and may result in protracted litigation which could delay the start of competition and interject more

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uncertainty into the process. The Company, therefore, urges the Commission to take into consideration and incorporate these Exceptions into the Proposed Order if it is to be adopted.

RESPECTFULLY SUBMITTED this 29th day of May, 1998.

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